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இலங்கை மின்சார சபை
CEYLON ELECTRICITY BOARD

Your ref: PUC/LIC/2023/CEB/22 My Ref: GP/CE/EXPAN-2023 Date: December 18, 2023

The Director General
Public Utilities Commission of Sri Lanka
6th Floor, BOC Merchant Tower
No.28, St, Michael's Road,
Colombo 3.

Clarifications on Input Data for Long Term Generation Expansion Plan (LTGEP) 2025-2044

We write in reference to your letter No. PUC/LIC/2023/CEB/22 dated 2023-12-13, requesting clarifications on the input data provided via our letter reference GP/CE/EXPAN-2023 dated 2023-11-17. Accordingly, please find the requested clarifications in the above referred letter as Annex 1.

Eng. (Dr.) Narendra De Silva
Actg. General Manager
Eng. (Dr.) Narendra De Silva
Actg. General Manager
Ceylon Electricity Board
Authorized officer for Licenses EL/T/09-002

ANNEX 1

Clarifications on Input Data for Long Term Generation Expansion Plan 2025-2044

1. **Significant increase (36%) in the capital cost of 300MW and 400MW NG Combined Cycle Candidates compared to the previous planning study.**

Gas Turbine World 2023 - GTW Handbook was referred to arrive at the cost figures for gas turbine and combined cycle power plant costs. As per the source mentioned above, it was mentioned that combined cycle power plant costs for 2023 is expected to be higher due to global economic impact. (Attachment – page 22 of 2023 GTW Handbook presents a cost increase of 10% over 2022 price levels. However, the costs used in LTGEP 2023-2042 was based on 2020 GTW Handbook and hence 36% cost increase is observed.)

2. **Coal plants are being considered as candidate plants despite the government policy direction to cease building of new coal-fired power plants.**

A reference case plan is required be developed with exclusion of any Policy Guidelines on generation technology options that would cause the plan to deviate from least cost. Therefore, several policy unconstrained scenarios shall be developed to identify the least cost generation expansion planning scenarios. However, in developing the base case scenario, coal power plants shall not be considered as candidates due to government policy direction.

3. **Whether the proposed plant capacity, respective cost parameters of Nuclear Plant Candidate and Nuclear fuel price were verified by the Sri Lanka Atomic Energy Board?**

CEB has requested nuclear power plant candidate technology data from the Atomic Energy Board to be used in long term generation expansion planning process. However, the information they have provided is not adequate and does not reflect the parameters utilized for planning studies. Therefore, CEB has notified the Atomic Energy Board that in the event such data is not received CEB shall proceed with the data available within CEB for preparation of LTGEP 2025-2044.

4. **Is the construction period of 5 years for the Nuclear Plant Candidate realistic?**

The construction time refers to the time taken from beginning of construction up to commissioning of the power plant. The construction period is used in planning studies for the investment plan, in disbursing the capital cost of the power plant. However, the lead time associated for a project with necessary studies and approvals are much higher and is not inclusive in the construction period. A period of 5 years is adequate for the construction of Nuclear Plant. The complete realization time of a nuclear power plant could be 10-15 years including construction. This will be appropriately considered in the planning process.

5. **The basis for the allocated weights in deriving fuel price forecasts.**

The weights of the fuel price forecast have been considered by apportioning higher prominence to most recent years.

6. **The purpose for which Hydrogen fuel price is used**

As already explained in letter GP/CE/EXPAN/-2023 dated 2023-11-17, candidate technologies that facilitates compliance with policy targets of carbon neutrality by year 2050, are required to be assessed. Hydrogen is a potential future fuel that enables complete decarbonization of the sector. Hydrogen can be produced locally from excess energy or be imported. Hence it is intended to be modelled appropriately in the current iteration of planning studies.

7. **Reasons for the increase in the Fixed O&M Cost of most of the ORE Candidate technologies compared to the previous planning study.**

In the new iteration of planning cycle, latest publications and reports were referred and the costs are reflective of the current context.

8. **Significant increase (22.8%) in the capital cost of Offshore wind candidate compared to the previous planning study**

The off shore wind technology parameters introduced in LTGEP 2023-2042 were based on preliminary assessments. However, during this iteration of planning studies, detailed study reports and reviews were consulted to capture the latest developments in these technologies. Sources are mentioned in the previous submission.

9. **Are the construction periods allocated for Offshore Wind and Mini hydro technologies Candidate realistic?**

For Mini hydro 1.5 years for construction is realistic when considering the real time implementation of same projects. (construction period excludes the time period for feasibility studies, environment studies and approval processes)

For wind power projects the following corrections need to be made.

Table 1: Construction years of ORE technologies

ORE Technology	Construction years
Onshore Wind	1.5
Offshore Wind (Fixed Bottom)	2.5
Offshore Wind (Floating)	2.5

10. Reason for considering firm capacity contribution to be below 100% (60% - 80%) from battery energy and pumped hydro storage technologies during the dry and wet seasons.

It is important to note that storage devices do not produce energy and only provide capability to time shift excess energy to critical periods. Hence the firm capacity of storage depends on the electricity production capabilities of other generation sources available in the grid. It has been analyzed that prolonged periods of extreme weather events occur during the wet and dry periods, resulting in non-availability sufficient power to charge/pump storage devices. As the future hydro potential is limited extreme deficits are foreseen, especially during wet seasons at the latter periods of planning horizon.

11. The forecasted demand, net loss, net generation and peak demand for 2024, and assumed demand for 2023 in the calculations

Demand estimation for 2023

At the time of estimation of demand for 2023 monthly sales up to May 2023 was available. Based on that and rooftop solar self-consumption estimates, the total estimated demand for 2023 was derived as 14,685 GWh. Considering the loss forecast obtained from distribution divisions net generation was forecasted as 16,000 GWh.

Demand forecast for 2024

Table 2: 2024 demand forecast

Year	Demand[1]	Net Loss[2]	Net Generation	Day Peak Demand	Night Peak Demand
	GWh	%	GWh	MW	MW
2024	15,481	8.10	16,844	2,588	2,574

[1] In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation.

[2] Net losses include losses at the Transmission & Distribution levels and excludes Generation (including auxiliary consumption) losses. Loss forecast will vary depending on the renewable thermal generation mix of the future.

12. Basis for considering a sudden drop of net loss in 2025 compared to the actual present system loss and the basis for assuming a day time peak demand from 2025 onwards

Basis for net loss forecast in 2025

Aggregated loss forecast for the period 2023 to 2029 is shown in figure 1 which is based on the divisional loss forecast provided by CEB and LECO distribution licensees. A gradual reduction is expected in the loss according to the data provided as shown in figure 1.

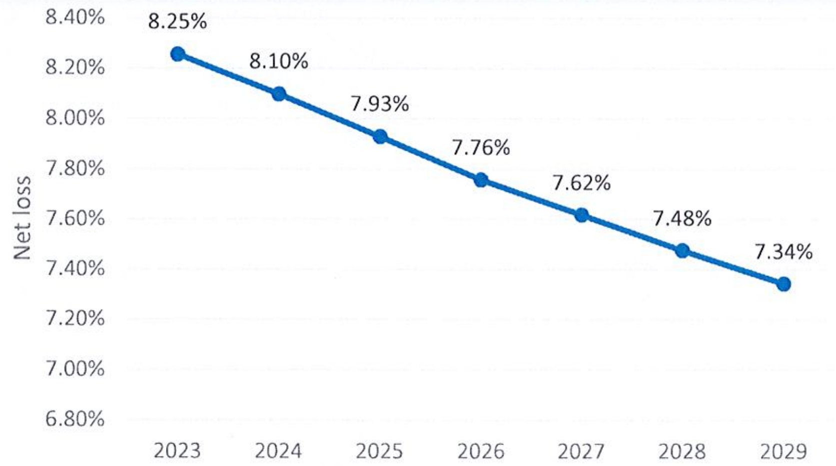

Figure 1: Loss Forecast based on DDs and LECO

Basis for assuming a day peak demand from 2025 onwards

In the process of developing the demand forecast, all embedded generation that is not metered real time at NSCC is evaluated to reflect the actual demand and generation. Therefore, the 15 min dispatch data obtained from system control center is adjusted to capture the rooftop solar and any other renewable power plants which are not metered real time. This adjustment is carried out based on estimated renewable resource profiles used for planning studies.

Data up to October 2023 was evaluated in this manner. Accordingly, it was estimated that on 31st August 2023 a maximum day peak of **2462 MW** has occurred (figure 2), whereas the recorded night peak for 2023 was **2415 MW** which occurred on 29th March 2023.

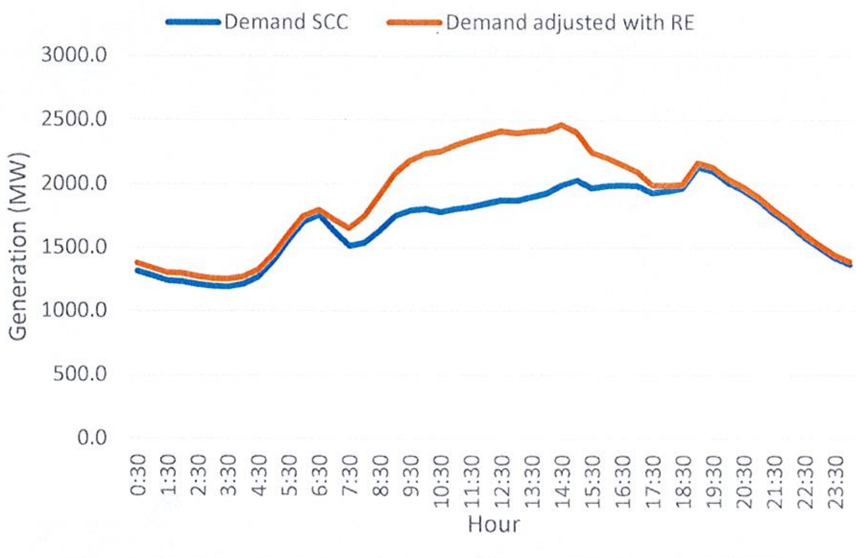

Figure 2: Adjusted demand profile on 31st August 2023

This adjustment was carried out for data from 1st January 2023 up to 31st of October 2023 (except the load shedding period) and it was observed that day peak exceeded night peak approximately 50%

of the days. Furthermore, this was validated by analysing the extrapolated trend lines of monthly records of day peak, night peak and off peak from 2011 to 2021 as shown in figure 3.

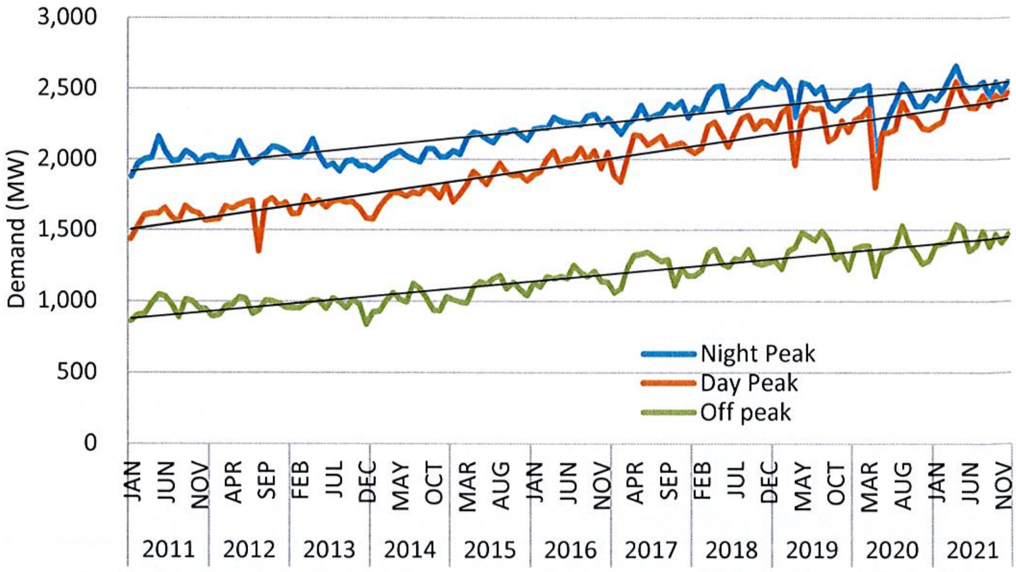

Figure 3: Analysis of Night Peak, Day Peak and Off Peak Trends 2011-2021

Hence, from the above analysis it was concluded that the occurrence of days with day peak exceeding night peak are common in the present system as well. However, due to the non-visibility of embedded generation and non-availability of some tele-metered data, real demand is not reflected in the published daily dispatch data. Accordingly, a day peak demand was assumed for the demand forecast 2025-2049 and day peak and night peak are separately presented.

13. Does the natural gas price include the handling charges related to the cost of regasification and transportation of fuel through pipeline network? What is the estimated handling charge (per MMBtu) used in the planning study?

The natural gas price does not include the cost of infrastructure for regasification and transportation of fuel. As explained in input submission letter, the annual requirement natural gas quantity varies significantly in planning scenarios and is not justifiable to apportion a single value as handling cost for fuel, to recover the investment cost. Hence in this iteration of planning studies LNG infrastructure is expected to be unbundled from fuel cost and modelled as an investment cost. However, the O&M Cost associated with operating the FSRU has been considered to be included in the fuel cost and the handling charge associated for the same is 0.7 US$/MMBtu.

The cost details related to LNG Infrastructure are as follows.

Table 3: LNG infrastructure cost breakdown

	CAPEX (Million US$)
FSRU	233
Mooring Facility	32
Pipeline (offshore and Onshore)	37

Note: Above values shall be escalated based on economic indicators for local and foreign escalation factors once they available for year 2024.

14. Have the inputs been taken from the distribution licensees for the demand projection (at least for the demand projection of next 4-5 years)?

Demand forecast including the contribution from rooftop solar and major projects was obtained from CEB and LECO distribution licensees for the period of 2023 to 2029 considering 5 years of planning horizon (2025-2029).

15. Has the demand for the Electric Vehicles as per the draft Policy for EV Transition for Sri Lanka been considered for the demand projection?

As per the discussions held with the Ministry of Transport and Highway a policy framework for EV transition is being prepared at present. As per the reference, "Kumarage A.S, A.G. T. Sugathapala and S. de Silva, Development of Policy Framework for EV Transition for Sri Lanka and Implementation Plan, Final Draft Report, Ministry of Transport & Highways, UNESCAP, November 2023", three scenarios have been projected considering business as usual (BAU), moderate and aggressive growth of EVs.

BAU scenario was obtained assuming that the existing growth rate of EVs will prevail in the future as well. Hence the trend of BAU EV growth is already captured in the demand forecast 2025-2049. It is suggested to carry out an additional scenario for aggressive EV growth scenario during the planning studies based on given data.

16. Has the roof top solar energy contribution of LECO consumers been included in the net generation projection?

Yes. Demand forecast data including the contribution from rooftop solar were obtained from LECO similar to CEB distribution divisions. Accordingly, roof top solar energy contribution of LECO consumers is included in the net generation projection.

17. It is recommended to validate the world bank fuel price forecast by reputed alternative forecasts and use only forecasted values to derive the fuel prices, as forecasts are anyway

derived incorporating the past fuel prices.

CEB has no objection in using only forecasted values to derive fuel prices as recommended by PUCSL. Following are latest version of published fuel price forecasts available for consideration.

Table 4: Sources of fuel price forecast

	Report	**Forecast Period**
World Bank	World Bank Commodity Price Forecasts, October, 2023	2024-2025
IEA	World Energy Outlook, 2023	2023-2050

Constant fuel prices derived based on above forecasts are as follows.

Table 5: Forecasted fuel prices

	Coal	**Natural Gas**	**Diesel**	**Furnace Oil**	**Naptha**
	US$/Mton	**US$/MMbtu**	**US$/bbl**	**US$/bbl**	**US$/bbl**
World Bank	133.0	11.2	112.2	116.7	86.1
IEA	121.3	11.6	116.5	121.2	89.3

CEB requires confirmation, on the fuel prices at initiation of planning studies.

Attachment

Combined Cycle Plant Prices

Budget prices for EPC contract to engineer, procure and construct standard design plants

GTW combined cycle budget prices are based on gas-only no-frills standard design combined cycle plants, built at locations with average non-union construction labor and good access for equipment delivery.

Prices represent so-called overnight costs, i.e., excluding escalation and interest during contract execution, and other time-dependent costs. With the intent of providing benchmark EPC contract costs (without contingency), the prices also exclude owner's costs, such as related to project development, land acquisition, permitting, utility interconnects, etc.

Besides defined plant scope of supply and boundary limits, the main factors that influence price include plant rating ("size matters"), type gas turbine (aero or frame), design platform and technology (E, F, G or advanced H and J-class), steam bottoming cycle design, number of gas turbines, and multi-shaft vs. single-shaft plant configuration.

Price update

As reflected by a steep increase in the market for large gas turbines, market activity for gas-fired combined cycle plants in 2022 showed a strong recovery from the pandemic-driven downturn of 2020-2021. However, continued steady growth of renewable capacity favors smaller simple cycle plants and seriously deters investment in major combined cycle projects.

On the other hand, a steady stream of coal-plant retirements provides strong support of the market for combined cycle plants, which offer a roughly 60% reduction in CO_2 emissions per kWh. Turning from coal to highly efficient hydrogen-ready gas-fired combined cycle technology is seen as an important part of many regional decarbonization plans.

A good number of orders for jumbo plants were recorded in gas-rich regions, such as the mid-east and also in gas-poor regions such as in much of Asia, where there is growing dependence on imported LNG.

Stiff competition among major OEMs and engineering/construction companies has kept combined cycle plant prices relatively low. However, inflationary pressures, as well as a continued strong demand, are expected to be reflected in increased plant prices for 2023.

The year-to-year increase in the Engineering News Record's Construction Cost Index for 2022, at around 4%, displayed a marked reduction from the peak inflation rates experienced in 2021.

However, when the increase in construction costs is combined with the lingering effects of the 2020-2021 spike in global inflation in equipment and material costs, the persistent supply chain issues and shortages of skilled labor, the overall increase in combined cycle plant prices for 2023 is expected to be only slightly lower than that predicted by GTW last year.

Moreover, this finding has been largely supported by specific information received from our annual field survey, especially for the larger plant category. Therefore, GTW's budgetary combined cycle plant price levels for 2023 again generally reflect an increase of 10 percent over 2022 price levels. (The increase in prices for smaller plants, rated at under 300MW, has been limited to 7.5%.)

Scope of Supply

Falls into three main categories: 1) gas and steam turbine power island, 2) balance-of-plant, and 3) EPC services:

- **Gas turbine.** Single-fuel skid-mounted DLE gas turbine with acoustic enclosure, starting motor, local control, plus standard mechanical and electrical auxiliaries normally supplied with simple cycle gas turbine package (standard inlet but without stack).

- **Steam turbine.** Condensing subcritical design, with single or dual-pressure levels for smaller plants, triple-pressure levels with reheat for larger advanced-design plants. Axial or downward exhaust, steam bypass, local controls, enclosure and water-cooled condenser. Plus auxiliary skid, all piping, valves and controllers (typically hydraulic).

- **Unfired HRSG.** Heat recovery steam generator designed for outdoor installation with short exhaust stack and silencing. Dual- or triple-pressure reheat design as dictated by gas turbine and steam turbine size and technology. Optional SCR for exhaust emissions reduction is excluded.

- **Generators.** Open air-cooled, enclosed water-air-cooled, or hydrogen-cooled designs, depending on turbine size. Neutral grounding cubicle and bus to main breaker included with generator packages. Single shaft configurations include only one generator.

- **Control system.** Distributed control system (DCS) for integrating gas turbine, HRSG and steam turbine controls with overall combined cycle plant control and operation.

- **Clutch.** For single-shaft arrangements, SSS (synchro-self-shifting) clutch assembly placed between steam turbine and generator enables gas tur-